COMMENTS OF INDIANA MICHIGAN POWER COMPANY, D/B/A AMERICAN ELECTRIC POWER, ON THE INDIANA UTILITY REGULATORY COMMISSION STAFF'S DISTRIBUTED GENERATION WHITE PAPER MARCH 1, 2002

On January 25, 2002, the Indiana Utility Regulatory Commission (IURC) initiated a preliminary discussion on the topic of distributed resources in Indiana as an outgrowth of the Commission's Reliability Proceeding (Cause No. 41736). The Commission requested that comments be submitted by March 1, 2002, on the IURC Staff Distributed Generation (DG) White Paper that accompanied its Advanced Notice of Proposed Rulemaking (ANOPR) on Distributed Resources. Additionally, the IURC scheduled a technical workshop for May 9, 2002.

The following comments are submitted on behalf of Indiana Michigan Power Company, a member of the AEP System family of companies, that does business in Indiana as American Electric Power (AEP). The AEP System is a multi-state integrated electric system providing electric service to over 4.8 million retail customers in eleven states: Indiana, Arkansas, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia, and West Virginia. Comments have been provided on the six topics included in the Staff's White Paper along with answers to the specific questions enumerated in Section 7 of the White Paper. This attempt to be as complete as possible has caused some of the comments on the White Paper and responses to the specific questions to be somewhat duplicative.

In addition to the comments, included as Attachments A and B are DG interconnection standards that AEP has filed in the States of Ohio, Virginia, and West

Virginia. It is our hope that these standards might serve as a basis for discussion of similar standards in Indiana and, as noted in our comments, these standards are compatible with the DG standards currently under development by the IEEE.

General comments on the IURC Staff White Paper topics are listed in Section I below and specific responses to Part 7 Questions are provided in Section II.

I. <u>General Comments On Staff White Paper</u>

1. Interconnection Standards

The IEEE P1547 standard that is currently being developed provides a good high-level guide to address many interconnection issues. However, the standard certainly does not address all of the issues that need to be included in this rulemaking proceeding. The IEEE standard lacks some requirements for performance, operation, testing, safety, and maintenance of the interconnection between the distributed resource and the electric power system. In addition, the standard contains very little regarding the responsibility of the DG owner to properly maintain their equipment, and the IEEE standard is silent regarding liability and indemnification. These issues are extremely important to the utility and should be addressed by the IURC rulemaking process. AEP has filed distribution interconnection standards in Ohio, Virginia, and West Virginia that are not only compatible with the IEEE Standards under development but also provide the detailed requirements that are necessary (and will not be developed by IEEE) to maintain the reliability and safety that customers, utility employees, and the general public expect (see Attachments A and B).

As DG technologies mature and the cost of DG decreases, use of DG owned by utilities or customers targeted to specific project locations selected by a utility can provide an economic alternative to investing in traditional infrastructure. DG can be important in the development of an optimal portfolio of future distribution delivery system expansion plans. For example, if the utility can target a DG installation to a particular site where it may have considered upgrading the system by traditional means (such as the construction of a new substation or feeder), then the DG installation may defer the need for the traditional distribution system infrastructure enhancement and allow the utility to use those capital funds on other needed projects. AEP is receptive to the development of rules that would provide incentives for utilities to work with DG customers to own and operate DG at strategic locations selected by the Company on the distribution system.

While AEP recognizes the potential distribution benefits of targeted DG, AEP must also caution the Commission that not all DG provides this same value. In fact, there exists the potential for DG installations to actually increase the costs to the distribution provider and, ultimately, possibly customers not installing or directly benefiting from the DG equipment. Consider the example of where the distribution company may have to improve an existing, or even build a new, distribution feeder in order to interconnect a DG site. Absent the DG installation, the distribution system expenditures would not have been necessary. Unless customers installing the DG bear all the costs associated with that DG, other customers neither installing nor necessarily benefiting from that DG will subsidize that cost causer.

2. Siting and Permitting

Responsibility for siting and permitting is typically housed with the local jurisdiction, such as a municipality or county, that is authorized to oversee building and electrical codes. Typically these jurisdictions will adopt national building and electrical codes but, in some cases, will adopt modifications to address local issues. It would be prudent to work with the appropriate national organizations to develop model language that could provide standards that could be adopted by local jurisdictions to address the siting and permitting of distributed resources.

In addition, the Department of Energy (DOE) provides a service that educates siting and permitting oversight entities regarding distributed resources. Drawing on their expertise would facilitate a knowledge base and comfort level with the technology. The IURC could also work with the Indiana Association of Cities and Towns (IACT), the Association of Indiana Counties (AIC), and other authorized oversight public entities to undertake a dialogue regarding this technology and work toward the development of a standardized code available for adoption by local jurisdictions.

Under Indiana regulations, environmental permitting requirements are ultimately driven by regulations issued by the Indiana Department of Environmental Management (IDEM). These requirements include exemptions from the permitting rules for certain small sources with minimal emissions as defined in 326 IAC 2-1.1-3. Any proposed source with emissions greater than those identified in this rule require either a registration or full permit that would take six to eighteen months to obtain, on average, depending on the size of the proposed source. It should also be noted that Indianapolis and Evansville have their own environmental regulatory agencies handling air quality issues with their own rules, but these rules tend to mirror the rules issued by IDEM.

In addition to air quality issues, certain sources may generate wastes that would be classified as hazardous wastes that would require, at a minimum, source or facility registration and possibly permitting. Further, any wastewater released from the facility and discharged to a receiving stream would likely require permitting under the National Pollutant Discharge Elimination System (NPDES) program and if discharged to a sanitary sewer, may require permitting with the appropriate municipal sewer authority. It is likely that either of these permitting activities could be done concurrently with any required air permitting but would be handled by a different Office of IDEM or an independent local authority.

3. Net Metering

The Company agrees with the IURC Staff that "net metering" is an arrangement where small customers offset their electric consumption and the meter is essentially allowed to run backwards. However, the Company does not believe that net metering is a requirement for a successful rulemaking involving DG. Net metering is a mechanism by which customers with DG are subsidized for the purpose of encouraging the development of DG. Any time a customer feeds power back to a utility's system, the customer is clearly entitled to some form of credit (or potential payment) for that power. However, the question becomes an issue of which customers should receive more than the applicable buy-back rate for such generation, and, thereby a subsidy for the purpose of encouraging DG. In the event that the IURC determines that net metering subsidies are necessary, the Company proposes the following guidelines for the application of net metering:

a. Net metering should be applicable only to customers who use DG equipment to offset a portion of their own usage.

b. Net metering should be limited to customers utilizing small, renewable sources of energy.

c. Net metering should apply only to relatively small customers served under residential or small commercial service schedules.

d. Customers can be served under the otherwise applicable standard service schedules with net metering provisions that apply only to the generation component of customer bills. This will appropriately limit any subsidy to the generation component of rates.

e. The transmission and distribution (T&D) components of rates should be charged based on the total energy flowing both in and out the customer's system and not on "net" metered values. The segmentation of generation is necessary to appropriately bill for T&D, which are functions of demand and not net energy.

f. Customers must be responsible for any additional metering costs required to measure energy flows in each direction as well as the net energy for generation billing purposes.

g. A maximum amount of load to which net metering can apply should be established for each utility. An appropriate limitation would be 0.1% of each utility's peak demand.

Most residential and small commercial tariffs include per kWh charges that recover bundled costs for generation, transmission, and distribution. Accordingly, for the purposes of net metering application, the generation portion must be separately identified. The application of net metering in this manner, for customers meeting the criteria set forth above, provides a reasonable balance of the factors that determine the appropriate credit for power fed back into the utility's system versus the costs imposed by the customer. As discussed in the Company's response regarding buy-back rates and recognized by the Staff in its report, the true cost of power is a function of time of day, time of year, and other factors that influence the Company's avoided costs. Net metering over-simplifies and ignores these factors by crediting the customer with the average rate paid by customers. However, it clearly would not be appropriate to credit the customer for T&D costs, as no such costs are avoided by an individual customer with DG.

Even limiting the application of net metering to the generation component creates a subsidy for such customers because net metering utilizes the structure of existing rates. Where existing rates are non-time differentiated, customers with net metering may utilize power during on-peak periods, feed back energy during off-peak periods, and still receive average charges and credits. It is the existence of such subsidies in any net metering arrangement that require net metering be applied on a limited basis. Limited applicability to DG facilities that utilize renewable sources can be justified if the environmental benefits sufficiently offset the subsidies associated with net metering.

4. Stranded Costs

AEP believes that the issue of stranded costs may need to be addressed at a later time if it becomes of significance. Limitations on the availability and the structure of net metering provisions will help to minimize any stranded costs.

5. Standby Rates

Regardless of whether or not a customer has net metering, if the utility is required to supply power to the customer in the event that the customer's DG equipment fails or requires an outage for maintenance, standby rates are applicable. Standby rates must reflect the true cost of serving customers on such a standby basis. Otherwise, other customers and the utility will subsidize those customers with DG who require standby service.

There are three types of standby services that a DG customer may require, all of which can be supplied by the utility if priced appropriately: (1) Supplemental Power, in the event that the DG output cannot meet the customer's full requirements in each and every hour; (2) Backup Power, in the event that a customer's DG equipment fails or requires an unscheduled outage; and (3) Maintenance Power, in the event of scheduled outages of a customer's DG equipment.

Standby rates should be designed for individual utilities based on their own unique costs and operational characteristics. These rates must reflect the proper costs of generation (which vary by time of day and season) as well as the fixed nature of T&D costs. Just as standard rates for customers with requirements above 10 kW utilize monthly demand charges ($/kW) for the recovery of costs, standby rates should also use monthly demand charges.

For customers with small DG facilities, standby rates can effectively be charged if generation is charged on a time-of-day basis when used and the customer pays the full cost of T&D each month regardless of usage. Such treatment of T&D costs is consistent with the appropriate treatment of T&D costs for net metering situations as discussed previously.

6. Buy-Back Rates

Buy-back rates generally refer to the price paid by the utility, or credited to a customer with DG, when power flows onto its system. However, the utility should not be required to pay for such energy from a DG operator at a price that is greater than the value of that energy to the utility. In reality, such energy generally has little value to the utility, as the customer's DG source is usually not dispatchable by the utility. The utility's only recourse when receiving DG energy may be to back down its own generation. Accordingly, the appropriate rate to be paid by the utility for such energy is the utility's avoided energy cost. Avoided demand costs can only be considered for sources that are dispatchable by the utility.

At a minimum, buy-back rates paid by the utility for energy from a DG source should be time-differentiated. This would appropriately align the price paid to the customer with the value of the power provided. For example, time-differentiated buy-back rates would prevent a DG operator from feeding energy back to the utility's system during off-peak times and receiving an average price (non-time of day) from the utility for that energy.

If a customer's DG is really a mechanism for generating energy as a for-profit business, then the customer is essentially an independent power producer and subject to FERC jurisdiction. Therefore, the Company proposes that any buy-back rate provisions considered by the IURC apply only to those DG facilities of customers whose generation is designed to offset the customer's load and not to those facilities whose purpose is the sale of power.

II. <u>Responses to Questions (Part 7)</u>

a. Please provide a definition of distributed generation, including engineering characteristics and unit size. Should the definition differ depending on the customer class?

Response:

As proposed in the IEEE P 1547 standard, distributed generation (DG) are sources of electric power generation with aggregate capacity of 10 Megawatts or less interconnected to the Company's distribution system at voltages of 35 kv or below. The aggregate capacity of the DG is determined at the point of common coupling where the customer's facilities connects to the Company. The point of common coupling may be at secondary distribution voltages of 480 volts or less or at primary distribution voltage levels of 35 kV or below.

AEP supports the grouping of DG into two categories—DG single phase 25 kW and below for residential and small commercial application and three phase DG for larger commercial and industrial application. This grouping allows for a simpler subset of technical requirements for the smaller DG units than the more complex technical requirements needed for larger three phase DG.

b. Assuming net metering as the first step in a DG rulemaking, what are the benefits for customers with net metering and what are the possible negative effects?

Response:

A benefit of net metering for customers is simplicity. Negative effects include the subsidization of customers with net metering by other customers and by the utility. This problem will be made even worse if net metering is not limited to only the generation component of rates. Net metering without time-differentiated provisions sends improper price signals to customers. It also provides the customer with no incentive to manage peak usage and is contrary to demand side management objectives.

c. What kind of tariff structure can be used to deal with different amounts and sizes of DG and still make net metering practical?

Response:

Net metering should be applicable only to customers seeking to offset a portion of their own usage. It should also be limited to small, renewable sources of energy. All net metering installations should be for relatively small customer loads served under residential or small commercial service schedules.

Customers can be served under otherwise applicable standard service schedules with net metering provisions for generation portions of customer bills. Net metering should apply only to the generation portion of a customer's monthly bill. Time-of-day provisions should also apply so as to meet demand side management objectives. Otherwise, the use of net metering may actually result in less efficient use of generation, i.e., the customer utilizes generation off the grid during on-peak times and feeds back into the grid during off-peak times.

A maximum amount of load to which net metering can apply should be established for each utility. An appropriate limitation would be 0.1% of the utility's peak demand.

d. How should a utility determine the fixed amount of cost per customer with net metering, for both a net buyer and/or net seller?

Response:

Net metering provisions should be applied only to the generation portion of a customer's billing. Transmission and distribution charges should be based on the total energy flowing both in and out of the customer's system and not on the "net" metered values. This will result in appropriate billing for transmission and distribution which are functions of demand and total usage and not net energy.

Customers must be responsible for any additional metering costs required to measure energy flows in each direction as well as the net energy for generation billing purposes.

Most residential and small commercial rates include per kWh charges that recover distribution and transmission costs as well as generation costs. In order to more accurately measure fixed vs. variable (generation) costs, existing rates would either need to be unbundled into their functional components or the generation portion should be separately identified. Then net metering provisions could be applied only to the true generation portion of customer rates.

e. How do tariffs need to be designed to adequately reflect the efficient recovery of the fixed and variable costs for service to customers that operate DG equipment using a net meter?

Response:

See the response to question d. above. Customers must be liable for all costs they cause the utility to incur.

f. How can stranded costs be identified and measured?

Response:

AEP believes that the issue of stranded costs may need to be addressed at a later time if it becomes of significance. Limitations on the availability and the structure of net metering provisions will help to minimize any stranded costs.

g. What, if any, are the benefits and revenues that should be considered as offsets to stranded costs?

Response:

Not applicable.

h. What rate design alternatives would reduce the potential for any stranded costs?

Response:

Limitations on the availability and structure of net metering provisions will help to minimize any stranded costs. However, because DG owners will still utilize the local utility's distribution and transmission facilities, the utility must retain the ability to determine energy flows in either direction for each hour of the billing period. Any specific charges or credits related to DG equipment operation should only be generation related and not related to T&D.

i. Should standby rates for backup power be used, and if so under what criteria?

Response:

Yes. With or without net metering, if the utility must stand ready to supply power to the customer in the event of customer DG equipment failure or during maintenance outages, standby rates should apply. However, standby rates must reflect the true cost of serving customers and the utility on a standby basis. If standby rates are at less than full cost, then other customers and the utility will subsidize those customers with DG.

For small DG facilities, standby rates can effectively be charged if generation is charged on a time-of-day basis and the customer pays the full cost of transmission and distribution each month regardless of usage.

j. What different kinds of standby services do customers with DG require and can the utility reasonably supply?

Response:

There are three types of standby services that a DG customer may require, all of which can be supplied by the utility if priced appropriately: (1) Supplemental power, in the event that the DG output cannot meet the customer's full load in each and every hour; (2) Backup power, in the event of customer DG equipment failure or unscheduled outages; and (3) Maintenance power, in the event of scheduled outages of customer DG equipment.

k. In order to determine the necessity and proper design of standby rates we need further information on distribution system design, operations, and cost structure. Please provide any information that might help to develop efficient standby rates.

Response:

Standby rates should be designed by individual utilities based on their own unique costs and operational characteristics. Standby rates must reflect the full cost of transmission and distribution. They must also reflect the appropriate generation costs on a time-of-day basis. Demand charges should be used for any requirements above 10 kW.

I. Are there areas in Indiana with distribution constraints?

Response:

All distribution feeders have constraints as to the type, location and size of electrical loading and/or DG combination a feeder can adequately and safely serve. The primary goal of the utility is to maintain a highly reliable electric system and to ensure the safety of both its employees and customers. As generation size increases, so does the interconnection complexity. As a result, there may be additional requirements by the utility in order to maintain established levels of safety and reliability. Any newly developed interconnection standards must allow utilities to maintain flexibility in determining the appropriate approach (guidelines and inspections) to ensure a safe and reliable interconnection.

Listed below are some perceived customer and utility issues that need to be addressed before installing any DG system. The issues are common to the customer and the utility.

(1) Interconnection guidelines:

- The lack of uniform specifications and consistent industry standards/guidelines regarding DG interconnections.
- Utilization of some DG technologies, which lack adequate testing/development, and may not have been proven in terms of their safe integration, performance, power quality, and reliability impacts on the utility's grid.

- Lack of consensus on how to interconnect the DG with the utility's grid to ensure employee and public safety.

- Lack of consensus on metering DGs. The metering configuration should involve two separate meters (one to measure and record energy flow "in" and one to measure and record energy flow "out") or one bi-directional meter that is capable of measuring and recording energy flow in and energy flow out.

(2) System interfaces:

- DG reliability and power quality (PQ) impacts on other utility customers. It is suggested that power quality should be monitored to ensure a source of energy supply containing a minimal amount of harmonics.

- Reliability of DG performance during the utility's peak demand period or during the utility's use of DG as a dispatchable resource.

- Forecasting DG availability and longevity. Difficulty can arise when estimating the utility's line and station capacity and demand growth. These measures are key elements in planning for prudent system improvements.

- DG harmonic distortion. Without proper interconnection guidelines, DG harmonics can adversely affect the utility and other customers' facilities.

- DG integrity and operations in conjunction with the utility's grid. Depending on the size of the DG system, the utility will require dispatch control.

- DGs can be prone to islanding/feedback situations and safety issues.

- DG stability and reliability impacts on radially designed distribution systems.

- Depending on the size of the DG application, significant engineering studies will be required. For example, impact studies, local facilities, and/or system improvement planning may be needed to accommodate the DG interconnection. The DG customer is responsible for improvements, such as service transformer upgrades, secondary and service drop replacement, etc., in order to preclude those costs from ultimately being incurred by non-participating or non-benefiting customers.

(3) Siting Requirements:

- Geographical location/conditions, local permits/approvals, environmental restrictions

- State, local, and regional codes

- Environmental, public, health and safety concerns, and restrictions

- Utility system constraints (i.e., voltage level)

m. Should utilities be required to file a location-specific set of T&D costs?

Response:

Due to the size and dynamic nature of the distribution system, the filing of location specific T&D costs for numerous locations would be a very costly and burdensome task and very difficult to keep current. Also, T&D cost information may be of limited value to customers since there may be significant DG interconnection cost variation from location to location depending upon the type and size of the DG. Customers wanting to site DG should work with the utilities to narrow the number of potential sites to those having the best potential benefit.

AEP is supportive of the development of rules for utilities to work with DG customers to own and operate DG at strategic locations selected by the Company on the distribution system. AEP envisions an annual targeted program with specific locations and required generation capacity determined by the Company. Requests for proposals would be initiated to ascertain which customers or third parties may be interested in owning DG at the specific locations designated by the Company. With such a program the maximum value of the DG installation can be realized to the benefit of all the parties.

n. What constitutes an economically efficient buy-back rate?

Response:

The utility should not be required to purchase energy from a DG operator at a price that is greater than the value of that energy to the utility. The energy fed back onto the utility's system may have little value to the utility, as that energy is generally non-dispatchable by the utility. A utility's only recourse may be to back down its own generation in order to utilize the DG energy. Thus, the appropriate rate the utility should pay for such energy is the utility's avoided energy cost rate.

"Buy-back" rates paid by the utility for such energy should, at a minimum, be differentiated by time of day as costs vary by time of day.

If a customer is generating energy as a for-profit business, the customer should make arrangements with an interested purchaser under the appropriate FERC jurisdiction.

o. What information should be included in a utility standard application form for distributed generation?

Response:

The information to be provided should include all the information necessary to evaluate and successfully integrate the DG facility with the utility's distribution system and to provide for compatible operation of the integrated facilities. Application forms for small units will require less information than for larger units.

Please refer to Appendix E of Attachment B for a comprehensive application form to cover all sizes and types of DG entitled “Notification of Intent to Install and Operated Distributed Energy Resource Interconnected with the Local Distribution Company’s (LDC) Distribution System” and Appendix B of Attachment B for a supplemental form entitled “Generation Dynamic Performance Data” to be used for three phase units.

p. What costs are incurred by a utility to review a DG project?

Response:

There are costs associated with the review of a proposed DG project. The activities associated with these costs may include the following:

1. Processing the request.
2. Coordinating, scheduling, and tracking the tasks necessary to properly evaluate the request.
3. Collecting and accounting for application fees, impact study deposits, and payments for system upgrade.
4. Processing the interconnection agreement.
5. Reviewing the request to confirm that the proposed DG meets the technical requirements for interconnection and determine if a system impact study is required.

6. Conducting system impact studies to determine if changes are required to the distribution system and/or the proposed DG installation to assure a safe and sound interconnection that will not adversely impact the reliability and/or power quality of other customers served by the distribution system.
7. Advising the customer on energy pricing, auxiliary power requirements, metering and other related non-technical service matters, and business issues.
8. Inspecting, verifying, witness testing, and approving the physical DG installation.
9. Confirming that all requirements have been met and issuing formal approval of the interconnection.
10. Adding the DG installation information to operating maps and records and advising operating personnel of the new DG installation.

Additional costs may result from the review, such as the cost to design, engineer, and construct required system improvements identified by the system impact study that are necessary to accommodate the DG installation.

q. Do these costs vary for different DG project proposals?

Response:

Yes, these costs can vary greatly depending upon the size, location, and type of DG facility.

r. How long should it take a utility to evaluate a project?

Response:

The time it takes to evaluate a DG project can vary widely depending upon the size, location, and type of DG and the completeness and accuracy of the information provided by the customer regarding their planned DG installation. AEP supports the use of a screening process to identify DG projects that can qualify for a simplified interconnection process. The screening process screens out DG projects that need further study from the DG projects that have a low risk of negatively impacting the distribution system. Once these low risk DG projects have been identified they can be processed more quickly than the DG projects requiring more study.

s. What are the criteria a utility should use to evaluate a DG project?

Response:

A utility should use criteria that provides for:

(1) Public and utility worker safety.

(2) Maintenance of adequate power quality and service reliability for other utility customers served by the distribution system.

(3) Recovery of costs fairly attributable to DG installation including the costs of interconnections and system upgrades made necessary by the DG installation to minimize the economic impact on the utility and its ratepayers.

Using these criteria, AEP has developed the DG interconnection technical requirements documents for DG interconnection enclosed as Attachments A and B, (Attached AEP Reports 780 A "Requirements for Connection of Small Distributed Energy Resource Facilities to the Local Distribution Company's

Distribution System, 25 kW and Below (Residential/ Small Commercial) Single Phase Application" and 780 B "Requirements for Connection of Distributed Energy Resource Facilities to the Local Distribution Company's Distribution System Three Phase Application), respectively.